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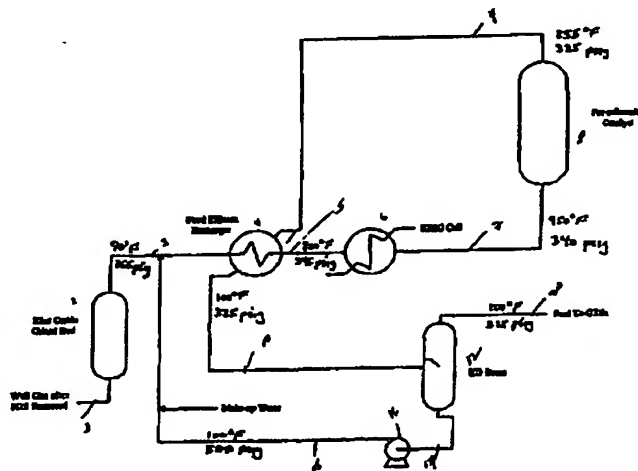
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(54) Title: METHOD FOR UTILIZING GAS RESERVES WITH LOW METHANE CONCENTRATIONS AND HIGH INERT GAS CONCENTRATIONS FOR FUELING GAS TURBINES



**(57) Abstract:** The invention is directed to a method of fueling gas turbines from natural gas reserves with relatively low methane concentrations. The invention uses such reserves to generate electric power. The invention permits the use of these reserves at significantly lower cost than by producing pipeline natural gas to fuel gas turbines to generate electric power. These reserves currently generally are used only after the removal of impurities to produce pipeline natural gas quality turbine fuel. The latter current technology is capital intensive, and at current natural gas prices, economically unattractive. The process of the invention can remove the impurities from the gas from the natural gas reserve necessary for protection of the environment, and leaves inert gasses in the fuel in an amount which will increase the output of a gas turbine for the generation of power by about 5 to about 20 %.

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*For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.*

## **METHOD FOR UTILIZING GAS RESERVES WITH LOW METHANE CONCENTRATIONS AND HIGH INERT GAS CONCENTRATIONS FOR FUELING GAS TURBINES**

This invention relates to the combustion of natural gas having relatively low methane concentrations and relatively high concentrations of inert gases. More particularly, this invention relates to the utilization of natural gas reserves having methane gas concentrations of from above 40 to about 80 volume percent methane by increasing the relative concentration of inert gases and using the methane produced thereby in a process which produces pipeline quality natural gas. In one aspect, hydrogen gas is blended to provide an inert gas and hydrogen enhanced methane gas blend with a methane gas concentration of not more than about 40 volume percent, based upon the total volume of the gas. This gas blend is used for fuel in gas turbines.

### **BACKGROUND OF THE INVENTION**

Currently there are substantial methane gas reserves with relatively low methane gas concentrations. Many of these reserves have methane gas concentrations from about 40 to about 80 volume percent. Currently, impurities are removed from natural gas to make pipeline quality natural gas which normally have methane concentrations of from about 95+ to about 99+ volume percent. To fuel gas turbines to make electric power, converting natural gas having methane concentrations of from about 40 to about 80 volume percent methane to pipeline quality natural gas becomes economically impractical because the conversion is capital intensive. Moreover, natural gas with methane concentrations in the range of 40 to 80 volume percent does not necessarily provide a reliable fuel source for gas turbines, especially at the low end of the latter range, to generate power with enhanced outputs of power because natural gas with such low methane concentrations will not provide a stable flame for fuel combustion without special equipment designs, catalysts and without special balancing of oxygen with other combustibles. Moreover, streams with 40 to 80 volume percent methane have the

problem of generating high NO<sub>x</sub> emissions as a result of higher flame temperatures in the turbine.

It would be economically advantageous to utilize natural gas reserves with 40 to 80 volume percent methane and with large amounts of inert gases and purify such streams or a portion of such streams to provide a fuel for gas turbines at significantly lower cost than by producing pipeline quality natural gas for fuel for gas turbines.

### SUMMARY OF THE INVENTION

The invention is directed to a method of fueling gas turbines from natural gas reserves with relatively low methane concentrations of from about 40 to about 80 volume percent and relatively high inert gas concentrations. The invention permits the use of these reserves at significantly lower cost than by producing pipeline natural gas to fuel gas turbines to generate electric power. As described, these reserves currently generally are used only after the removal of impurities to produce pipeline natural gas quality turbine fuel. Also as previously described, the latter current technology is capital intensive, and at current natural gas prices, economically unattractive. The process of the invention can remove the impurities from the gas from the natural gas reserve necessary for protection of the environment, and leaves inert gases in the fuel in an amount which will increase the output of a gas turbine for the generation of power by about 5 to about 20%. In one aspect the process of the invention contemplates leaving the inert gases in the fuel to maximize mass flow through the gas turbine and to increase power output without the expense of producing pipeline quality methane gas and blending additional inert gases into the fuel to additionally enhance the mass flow through the turbine and lower flame temperature to reduce NO<sub>x</sub> emissions.

In one aspect the process of the invention uses a natural gas stream and process which is being used to produce pipeline quality natural gas. In this aspect during the purification process inert gases are separated from methane gas in the natural gas reserves with from about 40 to about 80 volume percent methane. A separation may be made which removes only such an amount of methane to

provide an inert enhanced methane gas blend which is effective for providing an increase in output of power by a gas turbine of by about 5 to about 20% as compared to a turbine fueled with pipeline quality natural gas. The purified methane stream generated by this separation then may be sent for further purification to produce pipeline quality natural gas. Alternatively there may be a general separation of inert gases from the methane gas and the inert gases separated from the methane then are mixed with the natural gas stream which has not had the inert gases removed (or another gas stream with 40 to 80 volume percent methane) in an amount which will increase the output of the gas turbine by about 5 to about 20% as compared to a turbine fueled with pipeline quality natural gas.

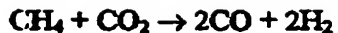
In one aspect where nitrogen gas is the primary inert gas, membranes are used to do the primary separation of the inert nitrogen gas from the natural gas and methane therein. Membranes commercially available and sold under the name of Medal from Air Liquide, Houston Texas, are suitable for such separation. This separation may be done only in an amount to increase the output of a turbine as previously described, or the nitrogen separated from the natural gas then is combined with the natural gas reserve to provide an inert enhanced natural gas which will increase the output of the turbine by about 5 to about 20% as compared to a turbine fueled with pipeline quality natural gas.

Membranes may be used to separate carbon dioxide and methane when the carbon dioxide concentration is up to about 45 volume percent. In another aspect where carbon dioxide is the primary inert gas at concentrations above about 45 volume percent, the carbon dioxide is separated from the natural gas reserve containing from about 40 to about 80 volume percent methane cryogenically. In one aspect when the pressure of the natural gas is high, such as greater than about 2500 psig, the high pressure feed gas is flashed to a lower pressure, such as about 500 psig. A Joule Thomson effect on this expansion is in an amount effective to provide a cooling to do a cryogenic separation. When the pressure of the natural gas reserve is low, such as below about 1100 psig the separation may be achieved an external refrigeration of the natural gas reserve to provide the cooling effective

for separating the carbon dioxide from the natural gas reserve and the methane there.

In a very important aspect, inert gases are separated from the natural gas reserve and the methane therein to provide a methane gas with less than about 40 volume percent methane. The methane separated from the natural gas reserve then may be sent for further processing to make pipeline equality natural gas. The inert gases separated from the natural gas stream then are mixed back into the natural gas stream from the well in an amount effective for providing a methane/inert gas blend having less than about 40 volume percent methane to provide an inert enhanced methane gas blend. The inert enhanced methane gas blend is blended with hydrogen, or in an important aspect, just enough methane is shifted to hydrogen gas to produce a gas fuel blend of hydrogen/inert gas/methane gas that not only is an acceptable fuel for gas turbines, but the blend is effective for providing flame stability (such as providing the gas with at least 110 BTUs per standard cubic foot of gas) and for producing more power than a standard natural gas having from about 95+ to about 99+ volume percent methane. If required, the hydrogen/inert gas/methane gas blend is dehydrated to remove a sufficient amount of water to provide a flame stable dehydrated hydrogen/inert gas/methane gas blend. In an important aspect, this blend has at least about 6 volume percent hydrogen. The flame stable hydrogen enhanced hydrogen/inert gas/methane gas blend then is used to fuel an electric power producing gas turbine. In this aspect, the method of the invention is effective for increasing the power output of a gas turbine by at least about 10 percent as compared to gas turbine using a standard natural gas which comprises from about 95 to about 99+ volume percent methane. In most cases in this aspect, output may be increased by at least about 20 and up to about 30 percent with these latter limits being imposed by the mechanical design limitations of the gas turbine.

In the aspect of the invention where methane is shifted to hydrogen gas, a portion of the methane from natural gas is catalytically converted or reformed into hydrogen gas which then forms the hydrogen enhanced methane/hydrogen gas blend. The reactions which obtain this conversion include:



In an another important aspect, especially where methane is shifted to hydrogen, prior to the conversion reaction, hydrogen sulfide and other acid components such as COS, RSH and RSSR are removed from the natural gas using a physical solvent to provide a sweet natural gas. A physical solvent selectively removes hydrogen sulfide and other acid gases, but minimizes the removal of inert gases, such as nitrogen and carbon dioxide and other inert gases such as helium and argon. In this aspect, the physical solvent is selected from the group consisting of methanol, a blend of dimethyl ethers of polyethylene glycol (molecular weight about 280), propylene carbonate (b.p. of 240°C, N-methyl-2-pyrrolidone (b.p. 202°C), a blend of oligoethylene glycol methyl isopropyl ethers (b.p. about 320°C), tri-n-butyl phosphonate (b.p. 180°C at 30 mm Hg) and methyl cyano-acetate (b.p. 202°C). The sweet natural gas is mixed with sufficient water to permit sufficient production of hydrogen from the methane to achieve flame stability or a BTU/Scf value of at least about 110. In this aspect, it is important that the hydrogen sulfide and other acid gases are removed prior to reforming a portion of the methane to hydrogen because the reformation is a catalyzed reaction where the catalyst may be poisoned by the hydrogen sulfide gas and other acid gases. Catalysts which are sensitive to the acid conditions and which may be used in this aspect of the invention include the C11 Series catalyst from United Catalyst Inc., R67 from Haldor Topsoe and G1-25 from BASF. High temperature "shift catalysts" for sweet natural gas generally are made from copper, zinc and aluminum.

In another important aspect, the reformation reaction is done under acid or sour conditions using catalysts such as a C25 Series catalyst from United Catalyst Inc., K8-11 catalyst from BASF and SSK catalyst from Haldor Topsoe. In general these catalysts are chrome/molybdenum catalysts. In this aspect of the invention, the sour natural gas and water are mixed with the water being in amount which will result in a methane gas/water blend which will permit the formation or reformation of sufficient hydrogen gas to provide flame stability for the hydrogen enhanced

inert gas/methane gas/hydrogen gas blend which does not have in excess of 40 volume percent methane.

After blending the inert gases with the natural gas reserves, the inert enhanced methane gas blend may have as low as 35, 25 or even less than 20 volume percent methane and still provide more power than pipeline quality methane when using hydrogen to provide flame stability to provide a fuel for gas turbines. In practicing this aspect of the invention, sufficient methane should be converted into hydrogen to produce a hydrogen enhanced hydrogen/inert gas/methane gas blend with at least 6 volume percent, and preferably from about 6 to about 10 volume percent hydrogen. This will produce a hydrogen enhanced hydrogen/inert gas/methane gas blend with stable flammability that is very effective for fueling gas turbines for the generation of electric power.

#### **BRIEF DESCRIPTION OF THE DRAWINGS**

Figure 1 is a flow plan illustrating the process of the invention where some of the methane is shifted to hydrogen gas to make a hydrogen/inert gas/methane gas blend for fuel for a gas turbine.

Figure 2 is a flow plan illustrating the process of the invention where high pressure feed natural gas is flashed to a lower pressure to separate methane gas from carbon dioxide gas both of which are present in the high pressure feed natural gas.

Figure 3 is a flow plan illustrating the process of the invention where low pressure feed natural gas is refrigerated using an external refrigeration device to separate methane gas from carbon dioxide gas both of which are present in a low pressure feed natural gas.

#### **DETAILED DESCRIPTION OF THE INVENTION**

A natural gas reserve having from about 40 to about 80 volume percent methane and a high relative concentration of inert gas such as nitrogen, carbon dioxide, helium and argon is conveyed to a separation unit to separate the inert



gases from the methane gas in the natural gas reserve. This produces a relatively pure methane stream and an inert gas/methane stream. If the reserve has high nitrogen content, the nitrogen gas can be separated from the methane gas using membranes, such as the Medal membranes. If the inert gas is carbon dioxide, the inert gas may be separated from the methane gas using a cryogenic separation as seen in Figures 2 and 3. After the methane gas is separated from the inert gas, the separated relatively pure methane gas may be conveyed to further purification apparatuses as are known to produce pipeline quality natural gas. If after the separation of the inert gas from the methane gas the inert gas/methane stream does not have sufficient inert gas to increase the power output of a gas turbine as described, then further inert gases may be added to the inert gas methane stream to increase the power output by from about 5 to about 20% as compared to a turbine fueled with pipeline quality natural gas. Alternatively, a portion of the natural gas stream which has not been separated from its inert gas components is further blended with inert gases, which have been separated from the reserve gas stream in an amount to provide an inert enhanced natural gas which will increase the output of the turbine by about 5 to about 20% as compared to a turbine fueled with pipeline quality natural gas.

In one important aspect, sufficient inert gases may be mixed with the inert gas/methane stream or with the natural gas reserve to lower the methane content of the methane gas in such a blend to less than 40 volume percent. In this aspect as can be seen by reference to Figure 1 the inert enhanced methane gas blend having a methane concentration of not more than about 40 volume percent is moved treated with a physical solvent such as methanol, a blend of dimethyl ethers of polyethylene glycol, propylene carbonate, N-methyl-2-pyrrolidone, a blend of oligoethylene glycol methyl isopropyl ethers, tri-n-butyl phosphonate, and methyl cyano-acetate to remove hydrogen sulfide gas and other acid gas components without removing inert gases to provide a sweet natural gas with not more than about 40 volume percent methane. Treatment with the physical solvent can be before or after separating the inert gas from the methane gas in the natural gas feed. The sweet inert methane gas blend then is conveyed via line 1 to a zinc oxide

guard bed 2 to prevent the emissions of hydrogen sulfide gas. The sweet inert methane gas blend is conveyed from the zinc oxide bed and mixed with water in line 3 to provide an inert enhanced methane gas/water blend. The gas/water blend is conveyed at about 70°F and at about 355 psig in line 3 to a feed effluent heat exchange 4 where the temperature of the sweet inert enhanced methane gas/water blend is raised to about 800°F. Sufficient water to be mixed with the gas blend to permit sufficient conversion to hydrogen to provide flame stability to a dehydrated hydrogen enhanced inert gas/methane/hydrogen gas blend when it is delivered to the gas turbine generator for the generation of power. After the sweet inert enhanced methane gas blend is mixed with water and heated in the feed effluent exchanger, the heated sweet inert enhanced methane gas/water blend is conveyed via line 5 at about 345 psig and about 800°F to a heat recovery steam generator coil (HRSG coil) to further raise the temperature of the sweet inert enhanced methane gas/water blend and provide a hot sweet gas/water blend having a temperature of about 950°F in line 3. The hot sweet gas/water blend then is conveyed via line 7 to a reforming reaction chamber 8 at about 340 psig for converting a part of the methane in the sweet inert enhanced methane gas/water blend to a hydrogen enhanced inert gas/methane/hydrogen gas/water blend. The methane in the sweet gas/water blend undergoes a catalyzed reaction to react the methane and water to produce hydrogen gas at least about 700°F and preferably from about 900 to about 950°F and about 340 psig. Higher temperatures facilitate the conversion, while higher pressures adversely affect the conversion. Pressure should not exceed 1500 psig. After conversion of sufficient methane to hydrogen to provide at least about 6 volume percent hydrogen in the gas present after dehydration (hereinafter described), the hydrogen enhanced inert gas/methane/hydrogen gas/water blend is conveyed back to the feed effluent exchanger via line 9 at about 855°F and 335 psig to transfer heat to the water and methane gas entering the feed effluent exchanger. After the temperature of the hydrogen enhanced inert gas/methane/hydrogen gas/water blend is reduced, it is conveyed via line 10 to a dehydrating knockout drum (KO drum) 12 to reduce the water content of the hydrogen enhanced inert gas/methane/hydrogen gas blend.

The dew point is lowered in the KO drum to permit water to condense and separate from the gas. Sufficient water is removed to permit flame stability and provide the gas with at least about 110 BTUs per standard cubic foot of gas. In general, from about 97 to about 99 or more weight percent of the water is removed from the gas. The water resulting from dehydrating the hydrogen enhanced inert gas/methane/hydrogen gas/water blend is removed from the KO drum 12 via line 14 using condensate pump 16 and is conveyed back to the feed effluent exchanger 4 via line 18 at about 100°F at about 500 psig. The dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend which now has at least 6 volume percent hydrogen or sufficient hydrogen gas to provide flame stability is fed from the KO drum to a gas turbine generator via line 20 at about 100°F at about psig. There the gas has at least about 110 BTUs per standard cubic foot of gas and provides a stable flame from the gas turbine generator.

The same process may be used in utilizing a sour natural gas using a catalyst which will not be sensitive or poisoned by the acid gases in the natural gas.

To keep the process compatible with the environment, however, at least some of the acid gases such as H<sub>2</sub>s may be removed at least in part.

The invention is illustrated by the following example.

#### EXAMPLE I

GAS TURBINE PERFORMANCE			
Site Conditions	Units	No Aug	Power Aug
Ambient Temperature	°F	60	60
Ambient Pressure	Psia	11.57	11.57
Ambient Relative Humidity	%	60	60
Inlet Pressure Drop	In H <sub>2</sub> O	3.0	3.0
Performance			

<b>GAS TURBINE PERFORMANCE</b>			
Gross Generator Output	KW	156,100	157,100
Heat Consumption (LHV)	Btu/h x 10 <sup>6</sup>	1,477.1	1,486.9
Heat Rate (LHV)	Btu/kWh	9,461	9,462
Misc.		1.8	1.8
LHV	Btu/Lb	2,424.0	2,424.0
	Btu/Scf	212.5	212.5
Fuel Gas Flowrate	lb/s	169.3	170.4
Pressure	Psia	325	325
Temperature	°F	80	80
Power Aug Inj Conditions			
Composition	% Vol		
Carbon Dioxide		100.0	100.0
Flowrate	lb/s	0.0	4.0
Pressure	Psia	285	285
Temperature	°F	300	300
Exhaust Gas Conditions	Units	No Aug	Power Aug
Exhaust Gas Flow	lb/s	925.3	930.4
Exhaust Gas Temperature	°F	1,093.1	1,095.1
Exhaust Gas Composition	% Vol		
Carbon Dioxide		13.79	14.12
Argon		1.07	1.07
Nitrogen		65.78	65.53

GAS TURBINE PERFORMANCE			
Oxygen		9.83	9.74
Water		9.53	9.55
Exhaust Pressure Drop	In H <sub>2</sub> O	15.0	15.0
Nox (Thermal)	ppmvd @ 15% O <sub>2</sub>	<10	<10

Data follows with respect to Figure 2 which illustrates the process of the invention where high pressure feed natural gas is flashed to a lower pressure to separate the methane gas from carbon dioxide gas both of which are present in the high pressure feed natural gas.

Data with respect to Figure 3 which illustrates the process of the invention where low pressure feed natural gas is refrigerated using an external refrigeration device to separate methane gas from carbon dioxide gas both of which are present in a low pressure feed natural gas.

**WHAT IS CLAIMED IS:**

1. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising:
  - providing a first natural gas stream from the natural gas reserve;
  - separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas;
  - blending the separated inert gas with a second natural gas stream having from about 40 to about 80 volume percent methane wherein after blending the amount of inert gas in the second natural gas stream will increase the output of a gas turbine by at least about 5 percent as compared to a turbine fueled with pipeline quality natural gas.
2. A method as recited in claim 1 wherein the inert gas includes nitrogen gas and the nitrogen gas is separated from the methane gas in the first natural gas stream with a membrane.
3. A method as recited in claim 1 wherein the inert gas includes carbon dioxide gas and the carbon dioxide gas is cryogenically separated from the methane gas in the first natural gas stream.
4. A method as recited in claim 3 wherein the cryogenic separation is done with a natural gas reserve with a high pressure feed having a pressure greater than about 2500 psig and the high pressure feed is expanded to a lower pressure which is effective to separate the carbon dioxide gas and the methane gas in the first natural gas stream.
5. A method as recited in claim 3 wherein the cryogenic separation is done with a natural gas reserve with a low pressure feed having a pressure lower than about 1100 psig and the low pressure feed is cooled with a refrigeration unit to a temperature which

effective to separate the carbon dioxide gas and the methane gas in the first natural gas stream.

6. A method as recited in claims 1, 2, 3, 4 or 5 wherein the separated methane from the first natural gas stream is processed into pipeline quality natural gas.

7. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas;

blending the separated inert gas, hydrogen, and a second natural gas stream having from about 40 to about 80 volume percent methane to provide a hydrogen enhanced inert gas/methane gas/hydrogen gas blend wherein the amount of inert gas blended with the second natural gas stream will decrease the relative percentage of methane gas to below about 40 volume percent methane, based upon the volumes of inert and methane gases, the hydrogen gas being in an amount effective for providing flame stability for the hydrogen enhanced inert gas/methane gas/hydrogen gas blend; and

fueling a gas turbine with the hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

8. The method for fueling a gas turbine as recited in claim 7 wherein the hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises at least about 6 volume percent hydrogen gas.

9. The method for fueling a gas turbine as recited in claim 7 wherein the method further includes dehydrating the natural gas or hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the dehydration effective for providing the

hydrogen enhanced inert gas/methane gas/hydrogen gas blend with at least about 110 BTUs per standard cubic foot of gas.

10. The method for fueling gas turbine as recited in claims 7 or 9 wherein the separated inert gas has less than about 35 volume percent methane, based on the volumes of methane and inert gases and the hydrogen enhanced inert gas/methane gas/hydrogen gas blend has from about 6 to about 10 volume percent hydrogen gas.

11. The method for fueling gas turbine as recited in claims 7 or 9 wherein the separated inert gas blend has less than about 20 volume percent methane, based on the volumes of methane and inert gases and the hydrogen enhanced inert gas/methane gas/hydrogen gas blend has from about 6 to about 10 volume percent hydrogen gas.

12. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas;

blending the separated inert gas and a second natural gas stream having from about 40 to about 80 volume percent methane to provide an enhanced inert gas/methane gas blend wherein the amount of inert gas blended with the second natural gas stream will decrease the relative percentage of methane gas to below about 40 volume percent methane, based upon the volumes of inert and methane gases;

removing at least one acid component from the inert enhanced inert gas/methane gas blend to provide a sweet inert enhanced inert gas/methane gas blend or removing at least one acid component from the first natural gas stream so as to provide a sweet inert enhanced inert gas/methane gas blend;



mixing the sweet inert enhanced inert gas/methane gas blend and water to provide a hydrated sweet inert enhanced inert gas/methane gas blend, the water in the hydrated sweet inert enhanced inert gas/methane gas blend being in amount effective for permitting the conversion of a portion of the methane in the sweet inert enhanced inert gas/methane gas blend to hydrogen gas and effective for providing a flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend;

catalytically converting a portion of the methane to hydrogen gas in the hydrated sweet inert enhanced inert gas/methane gas blend to provide a hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the conversion effective for providing the flame stable dehydrated natural gas;

dehydrating hydrogen enhanced inert gas/methane gas/hydrogen gas blend to provide the flame stable dehydrated hydrogen enhanced natural gas; and

fueling a gas turbine with the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

13. The method for fueling a gas turbine as recited in claim 12 wherein removing the acid component from the first natural gas stream or the inert enhance inert gas/methane gas blend includes removing hydrogen sulfide from the natural gas.

14. The method for fueling a gas turbine as recited in claim 12 wherein the hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend is dehydrated in an amount effective for providing the dehydrated hydrogen enhanced natural gas with at least about 110 BTUs per standard cubic foot of gas.

15. The method for fueling a gas turbine as recited in claim 13 wherein the hydrogen sulfide is removed from the first natural gas stream or the inert enhanced inert gas/methane gas blend with a physical solvent while minimizing removal of any inert gas.

16. The method for fueling a gas turbine as recited in claim 15 wherein the physical solvent is selected from the group consisting of methanol, a blend of dimethyl ethers of polyethylene glycol, propylene carbonate, N-methyl-2-pyrrolidone, a blend of oligoethylene glycol methyl isopropyl ethers, tri-n-butyl phosphonate, methyl cyano-acetate and mixtures thereof.

17. The method for fueling a gas turbine as recited in claim 12 wherein the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises at least 6 volume percent hydrogen gas.

18. The method for fueling a gas turbine as recited in claim 12 wherein the methane in the hydrated sweet inert enhanced inert gas/methane gas blend is catalytically converted using a shift catalyst selected from the group consisting of iron/chrome/copper, copper/zinc/aluminum and mixtures thereof.

19. The method as recited in claims 12 or 14 wherein the inert enhanced inert gas/methane gas blend does not have more than about 35 volume percent methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

20. The method as recited in claims 12 or 14 wherein the inert enhanced inert gas/methane gas blend does not have more than about 20 volume percent methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

21. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas;

blending the separated inert gas, water and a second natural gas stream having from about 40 to about 80 volume percent methane to provide a sour inert enhanced inert gas/methane gas/water blend wherein the amount of inert gas blended with the second natural gas stream will decrease the relative percentage of methane gas to below about 40 volume percent methane, based upon the volumes of inert and methane gases, the water in the sour inert enhanced inert gas/methane gas/water blend being in amount effective for permitting the conversion of a portion of the methane in the sour inert enhanced inert gas/methane gas/water blend to hydrogen gas to provide a hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend and effective for providing a flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend;

catalytically converting a portion of the methane to hydrogen gas in the sour inert enhanced inert gas/methane gas/water blend to provide a hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the conversion effective for providing the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend;

dehydrating hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend to provide the flame stable dehydrated inert enhanced inert gas/methane gas/hydrogen gas blend; and

fueling a gas turbine with the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

22. The method for fueling a gas turbine as recited in claim 21 wherein the hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend is dehydrated in an amount effective for providing the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend with at least about 110 BTUs per standard cubic foot of gas.

23. The method for fueling a gas turbine as recited in claim 21 wherein the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises at least 6 volume percent hydrogen gas.

24. The method for fueling a gas turbine as recited in claim 21 wherein the methane in the sour inert enhanced inert gas/methane gas/water blend is catalytically converted using a chrome/molybdenum catalyst.

25. The method as recited in claims 21 or 22 wherein the sour inert enhanced inert gas/methane gas/water blend does not have more than about 35 volume percent methane gas, based upon the volumes of methane and inert gases, and the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

26. The method as recited in claims 21 or 22 wherein the sour inert enhanced inert gas/methane gas/water blend does not have more than about 20 volume percent methane gas, based upon the volumes of methane and inert gases, and the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

27. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising:

providing a natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the natural gas stream to provide a separated methane gas and a separated inert gas/methane gas blend wherein the separation is made such that when the inert gas methane gas blend is used as turbine fuel there is an amount of inert gases in the blend which is effective for permitting the blend to increase an output of the gas turbine by at least about 5 percent as compared to a turbine fueled with pipeline quality natural gas.

28. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas/methane gas blend having less than 40 volume percent methane;

blending the separated inert gas/methane gas blend and hydrogen to provide a hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the hydrogen gas being in an amount effective for providing flame stability for the hydrogen enhanced inert gas/methane gas/hydrogen gas blend; and

fueling a gas turbine with the hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

29. The method for fueling gas turbine as recited in claim 28 wherein the separated inert gas/methane gas blend has less than about 35 volume percent methane, based on the volumes of methane and inert gases and the hydrogen enhanced inert gas/methane gas/hydrogen gas blend has from about 6 to about 10 volume percent hydrogen gas.

30. The method for fueling gas turbine as recited in claim 28 wherein the separated inert gas/methane gas blend has less than about 20 volume percent methane, based on the volumes of methane and inert gases and the hydrogen enhanced inert gas/methane gas/hydrogen gas blend has from about 6 to about 10 volume percent hydrogen gas.

31. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert gas/methane gas blend having less than about 40 volume percent methane;

removing at least one acid component from the separated inert gas/methane gas blend to provide a sweet inert enhanced inert gas/methane gas blend;

mixing the sweet inert enhanced inert gas/methane gas blend and water to provide a hydrated sweet inert enhanced inert gas/methane gas blend, the water in the hydrated sweet inert enhanced inert gas/methane gas blend being in an amount effective for permitting the conversion of a portion of the methane in the sweet inert enhanced inert gas/methane gas blend to hydrogen gas and effective for providing a flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

Catalytically converting a portion of the methane to hydrogen gas in the hydrated sweet inert enhanced inert gas/methane gas blend to provide a hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the conversion effective for providing the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend;

dehydrating hydrogen enhanced inert gas/methane gas/hydrogen gas blend to provide flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend; and

fueling a gas turbine with the dehydrated flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

32. The method for fueling a gas turbine as recited in claim 31 wherein the methane in the hydrated sweet inert enhanced inert gas/methane gas blend is catalytically converted using a shift catalyst selected from the group consisting of iron/chrome/copper, copper/zinc/aluminum and mixtures thereof.

33. The method as recited in claim 32 wherein the sweet inert enhanced inert gas/methane gas blend does not have more than about 35 volume percent

methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

34. The method as recited in claim 32 wherein the sweet inert enhanced inert gas/methane gas blend does not have more than about 35 volume percent methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

35. A method of fueling a gas turbine with methane gas from natural gas reserves having from about 40 to about 80 volume percent methane, the method comprising;

providing a first natural gas stream from the natural gas reserve;

providing a first natural gas stream from the natural gas reserve;

separating inert gases from methane gas in the first natural gas stream to provide a separated methane gas and a separated inert enhanced inert gas/methane gas blend having less than about 40 volume percent methane;

mixing the separated inert enhanced inert gas/methane gas blend and water to provide a hydrated inert enhance inert gas/methane gas blend, the water in the hydrated sweet inert enhanced inert gas/methane gas blend being in an amount effective for permitting the conversion of a portion of the methane in the inert enhance inert gas/methane gas blend to hydrogen gas and effective for providing a flame stable dehydrated hydrogen enhanced inert gas/methane gas hydrogen gas blend;

Catalytically converting a portion of the methane to hydrogen in the inert enhanced inert gas/methane gas/water blend to provide a hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend, the conversion effective for providing the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend;

dehydrating hydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend to provide flame stable dehydrated inert enhanced inert gas/methane gas/hydrogen gas blend; and

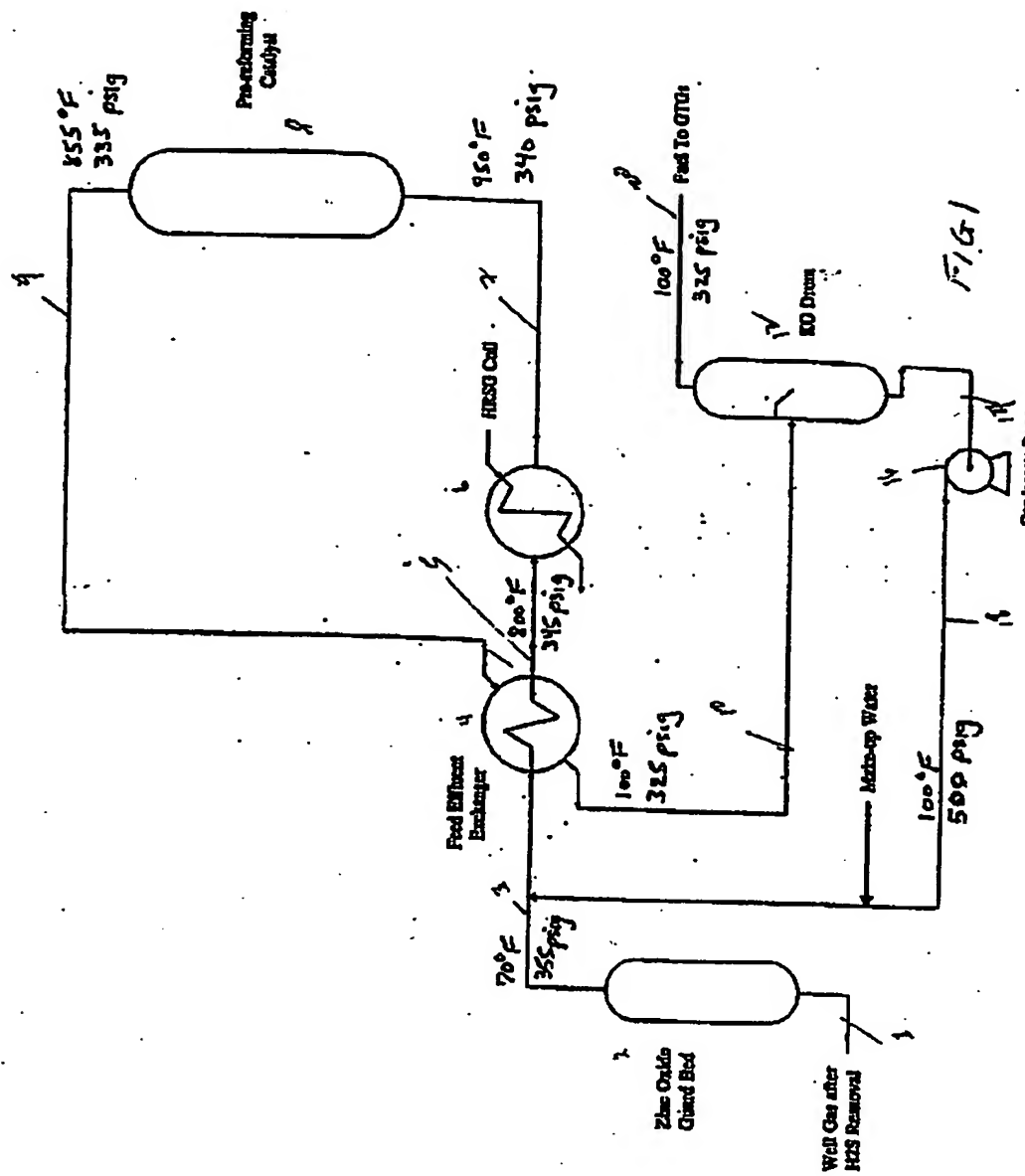
fueling a gas turbine with the flame stable dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend.

36. The method for fueling a gas turbine as recited in claim 35 wherein the methane in the inert enhanced inert gas/methane gas/water blend is catalytically converted using a chrome/molybdenum catalyst.

37. The method as recited in claim 36 wherein the inert enhanced inert gas/methane gas blend does not have more than about 35 volume percent methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.

38. The method as recited in claim 36 wherein the inert enhanced inert gas/methane gas blend does not have more than about 35 volume percent methane and the dehydrated hydrogen enhanced inert gas/methane gas/hydrogen gas blend comprises from about 6 to about 10 volume percent hydrogen gas.





Highest Pressure (early in field life)  
2570 PSIA Downstream of choke

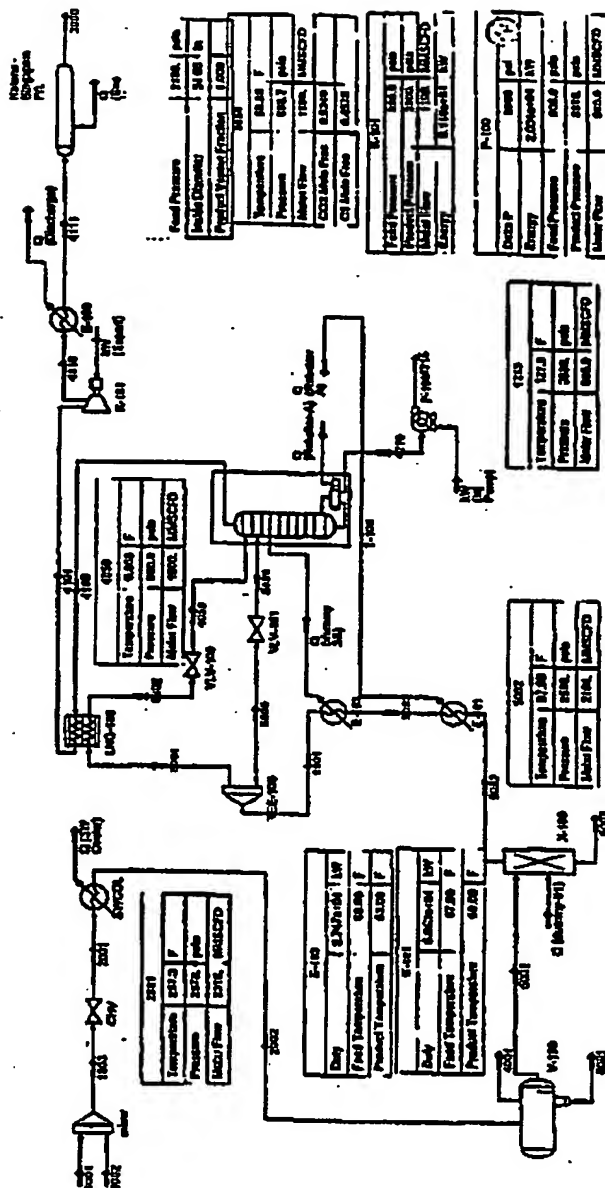


FIG. 2

Later in field life or higher well rates  
2070 psia downstream of choke  
Lower tower pressure

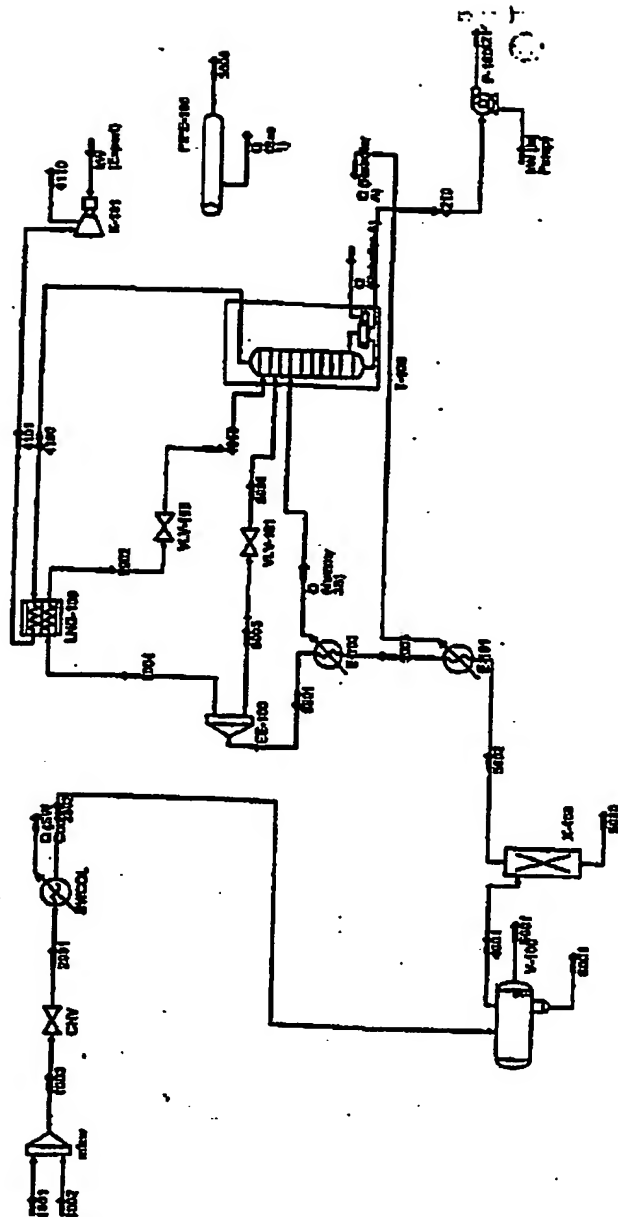


Fig 3

Refuxed 2570 FW:IP 1378 Miscd.

	Composition				Heat Content, Btu / Gall				HHV		Oxide		Prod
	Feed	Steam	Fuel	Waste	FEED	Gases	Fuel	Waste	BTUSCF	Recoy	Recoy	Recoy	
Instant Miscd	2500	1378.0	36.9	1122.0									
An. Ave. Miscd	1925.0	1081.1	28.4	883.9									
Instant GBTU/D					734.1	856.9	17.85	88.8					
An. Ave. GBTU/D					585.2	505.8	13.8	81.5					
% HC Loss GBTU/D							2.35%	8.02%	11.38%				
N2	0.004108	0.007412	0.007412	0.000660	0	0	0	0	0.0		85%		1%
CO2	0.712809	0.823522	0.823522	0.948507	0	0	0	0	0.0		40%		80%
H2S	0.005859	0.003471	0.003471	0.008346	0	0	0	0	0.0		34%		66%
C1	0.288371	0.488964	0.488964	0.084304	271	464	464	35	1010.0		84%		8%
C2	0.005108	0.005190	0.005190	0.005003	8	8	8	8	1768.6		56%		44%
C3	0.001689	0.000880	0.000880	0.002359	4	2	2	6	2516.1		34%		66%
ICA	0.000399	0.000164	0.000164	0.000688	1	1	1	2	3251.8		23%		77%
nC4	0.000388	0.000131	0.000131	0.000728	1	0	0	2	3262.3		18%		82%
IC5	0.000185	0.000042	0.000042	0.00038	1	0	0	2	4000.9		12%		88%
nC6+	0.000482	0.000087	0.000087	0.000889	2	0	0	4	4008.9		10%		90%
IC8+	0.000758	0.000000	0.000000	0.000000	4	0	0	0	5502.6		0%		100%
H2O	0.000005	0.000047	0.000047	0	0	0	0	0	0.0				
Totals	1.000000	1.000000	1.000000	0.998362	284	477	477	80					

Availability = 77%

Power, MW	Total	GT1	GT2	Eleo
Refrigeration R404a/CO2	0.00	0.00		
SG1	58.85		58.85	
SG2	0.00		0.00	
CO2 Injection Pump	23.50			23.50
Cond Flash Gas	0.00			0.00
Total MW	82.35	0.00	58.85	23.50
No. of LMR000s	2	0	1	1
Fuel	GBTU/D	17.81	12.58	8.03

Total Horsepower  
110,431 HP  
624 Miscd HC  
177 HP/Miscd

LMR000  
44,600 HP @ 80F  
33,184 KW @ 80 F  
8,544 Heat Rate, BTU / hp  
7,098 GBTU/D @ full power

B. Y. N. D. J. J. J. J. J.



HYSYS Simulation - Recycle (AR) Pages 250 - 1st 200 M at 45% C1.hsc						
Case (Main)						
Streams						
Name	S002	S003	S004	S005	S006	
Vapor Fraction	1.0000	0.0000	0.0000	0.0000	0.0000	
Temperature (°F)	87.50	83.00	83.00	83.00	83.00	0.3721
Pressure (psia)	2500	2498	2498	2498	2498	14.30
Molar Flow (lbmol/hr)	2154	2154	2498	2498	2498	800.8
Mass Flow (lb/hr)	8.655e+06	8.655e+06	7.210e+06	7.210e+06	7.210e+06	323.5
Liquid Volume Flow (bbl/day)	8.773e+05	8.773e+05	7.271e+05	7.271e+05	7.271e+05	1.458e+04
Heat Flow (Btu/hr)	-3.211e+06	-1.261e+06	-3.745e+06	-1.261e+06	-1.261e+06	1.458e+05
Comp Mole Frac (Nitrogen)	0.0041	0.0041	0.0041	0.0041	0.0041	-1.564e+06
Comp Mole Frac (CO2)	0.7123	0.7123	0.7123	0.7123	0.7123	0.0041
Comp Mole Frac (H2S)	0.0053	0.0053	0.0053	0.0053	0.0053	0.7123
Comp Mole Frac (Methane)	0.2633	0.2633	0.2633	0.2633	0.2633	0.0053
Comp Mole Frac (Ethane)	0.0011	0.0011	0.0011	0.0011	0.0011	0.2633
Comp Mole Frac (Propane)	0.0016	0.0016	0.0016	0.0016	0.0016	0.0011
Comp Mole Frac (i-C4)	0.0009	0.0009	0.0009	0.0009	0.0009	0.0016
Comp Mole Frac (n-C4)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0009
Name	S009	S001	S001	S002	W (Export)	
Vapor Fraction	—	0.0000	0.0000	0.0000	—	
Temperature (°F)	—	80.00	80.00	83.00	—	
Pressure (psia)	19.00	2500	2498	2498	—	
Molar Flow (lbmol/hr)	12.10	2500	2498	2498	—	
Mass Flow (lb/hr)	2.334e+04	8.655e+06	7.210e+06	7.210e+06	—	
Liquid Volume Flow (bbl/day)	1842	8.773e+05	7.271e+05	7.271e+05	—	
Heat Flow (Btu/hr)	—	-1.261e+06	-3.745e+06	-1.261e+06	—	
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0041	0.0041	—	5.118e-04
Comp Mole Frac (CO2)	0.0000	0.0000	0.7123	0.7123	—	
Comp Mole Frac (H2S)	0.0000	0.0000	0.0053	0.0053	—	
Comp Mole Frac (Methane)	0.0000	0.0000	0.2633	0.2633	—	
Comp Mole Frac (Ethane)	0.0000	0.0000	0.0011	0.0011	—	
Comp Mole Frac (Propane)	0.0000	0.0000	0.0016	0.0016	—	
Comp Mole Frac (i-C4)	0.0000	0.0000	0.0009	0.0009	—	
Comp Mole Frac (n-C4)	0.0000	0.0000	0.0000	0.0000	—	
Name	W (In Pump)	Q (Discharge)	Q (dummy 1B)	Q (dummy 01)	Q (Reboiler A)	
Vapor Fraction	—	—	—	—	—	
Temperature (°F)	—	—	—	—	—	
Pressure (psia)	—	—	—	—	—	
Molar Flow (lbmol/hr)	—	—	—	—	—	
Mass Flow (lb/hr)	—	—	—	—	—	
Liquid Volume Flow (bbl/day)	—	—	—	—	—	
Heat Flow (Btu/hr)	—	—	—	—	—	
Comp Mole Frac (Nitrogen)	—	—	—	—	—	6.052e-04
Comp Mole Frac (CO2)	—	—	—	—	—	
Comp Mole Frac (H2S)	—	—	—	—	—	
Comp Mole Frac (Methane)	—	—	—	—	—	
Comp Mole Frac (Ethane)	—	—	—	—	—	
Comp Mole Frac (Propane)	—	—	—	—	—	
Comp Mole Frac (i-C4)	—	—	—	—	—	
Comp Mole Frac (n-C4)	—	—	—	—	—	
Remarks:						
Date:						
Specified by user.						
HYSYS v1.2.2 (Build 17061) Page No: 2 of 4						

Instant	Macid	Composition			Heat Content, BTU/lb			HHV BTU/lb	O/H/D Recy	Prod Recy
		Feed	Sub/Fuel	Waste	Feed	Sub	Waste			
An. Ave.	Macid	1081	814.8	17.1	482.2					
An. Ave.	GBTU/D	1027.0	884.1	16.3	442.8					
% HC Loss	GBTU/D									
N2		0.004108	0.007207	0.007207	0.000021			10.80%		
CO2		0.712809	0.535284	0.535284	0.947178			0.0	100%	0%
H2S		0.005659	0.003558	0.003558	0.009300			0.0	45%	57%
C1		0.268371	0.447200	0.447200	0.032541			0.0	36%	61%
C2		0.005106	0.005267	0.005267	0.004894			1010.0	96%	5%
C3		0.001598	0.001010	0.001010	0.002376			1788.6	88%	41%
iC4		0.000389	0.000168	0.000168	0.000704			2818.1	36%	64%
nC4		0.000398	0.000134	0.000134	0.000746			3251.9	24%	76%
iC5		0.000189	0.000043	0.000043	0.000402			3252.3	19%	81%
nC5		0.000482	0.000087	0.000087	0.001028			4000.9	12%	88%
C6+		0.000758	0.000000	0.000000	0.000000			5502.5	10%	90%
H2O		0.000006	0.000000	0.000000	0.000000			0.0	0%	100%
Totals		1.520000	1.000000	1.000000	0.856317	284	465	465	59	

Availability = 85%

Power, MW	Total	GT1	GT2	Elec
Refrigeration R104a/CO	0.00	0.00		
SG1	27.58		27.58	
SG2	0.00		0.00	
CO2 Injection Pump	0.00			9.69
Condry Flash Gas	0.00			0.00
Total MW	37.25	0.00	27.58	9.69
No. of LM6000s	2	0	1	1
Fuel	7.97		8.39	2.67

Total Horsepower  
49,952 HP  
HC Sales  
271 Macid HC  
184 HP/Macid

1.225E+01 1.377E+01 1.112E+01

HYSYS Workbook: pats-FAB Dehy & Reflux. Column 2070 FWHP.hsc					
Main: Streams					
Streams					
Name	8003	8004	8005	8006	8000
Vapor Fraction	1.0000	0.0000	0.0000	0.0000	0.0000
Temperature (F)	62.00	61.00	61.00	13.30	---
Pressure (psia)	1920	1920	1920	1920	---
Molar Flow (lbmol/hr)	1920	1920	1920	1920	1920
Mass Flow (lb/hr)	4.332e+08	3.604e+08	7.705e+07	7.713e+07	4.871
Liquid Volume Flow (bbl/hr)	4.357e+05	3.635e+05	7.348e+04	7.348e+04	633.9
Heat Flow (Btu/hr)	-4.839e+06	-3.895e+06	-7.919e+05	-7.919e+05	-2.192e+04
Comp Mole Frac (Nitrogen)	0.0041	0.0041	0.0041	0.0041	0.0000
Comp Mole Frac (CO2)	0.7123	0.7123	0.7123	0.7123	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Methane)	0.2837	0.2837	0.2837	0.2837	0.0000
Comp Mole Frac (Ethane)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (Propane)	0.0000	0.0000	0.0000	0.0000	0.0000
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	0.0000	0.0000
Name	8901	8901	8902	8906 (Export)	8906 (In Pump)
Vapor Fraction	0.0000	0.0000	0.0000	---	---
Temperature (F)	60.00	60.00	60.00	---	---
Pressure (psia)	2000	1920	1920	---	---
Molar Flow (lbmol/hr)	81.43	1920	1920	---	---
Mass Flow (lb/hr)	1.190e+04	4.332e+08	3.604e+08	---	---
Liquid Volume Flow (bbl/hr)	9530	4.357e+05	3.635e+05	---	---
Heat Flow (Btu/hr)	-2.718e+05	-4.839e+06	-3.895e+06	---	---
Comp Mole Frac (Nitrogen)	0.0000	0.0041	0.0041	---	---
Comp Mole Frac (CO2)	0.0000	0.7123	0.7123	---	---
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	---	---
Comp Mole Frac (Methane)	0.0000	0.2837	0.2837	---	---
Comp Mole Frac (Ethane)	0.0000	0.0000	0.0000	---	---
Comp Mole Frac (Propane)	0.0000	0.0000	0.0000	---	---
Comp Mole Frac (H2O)	0.0000	0.0000	0.0000	---	---
Name	Q (Journey 3B)	Q (Reboiler A)	Q (Reboiler A)	Q (Sea 1)	Q (SW Cooler)
Vapor Fraction	---	---	---	---	---
Temperature (F)	---	---	---	---	---
Pressure (psia)	---	---	---	---	---
Molar Flow (lbmol/hr)	---	---	---	---	---
Mass Flow (lb/hr)	---	---	---	---	---
Liquid Volume Flow (bbl/hr)	---	---	---	---	---
Heat Flow (Btu/hr)	1.204e+04	2.142e+04	2.142e+04	---	1.380e+03
Comp Mole Frac (Nitrogen)	---	---	---	---	---
Comp Mole Frac (CO2)	---	---	---	---	---
Comp Mole Frac (H2O)	---	---	---	---	---
Comp Mole Frac (Methane)	---	---	---	---	---
Comp Mole Frac (Ethane)	---	---	---	---	---
Comp Mole Frac (Propane)	---	---	---	---	---
Comp Mole Frac (H2O)	---	---	---	---	---
Remarks:					
Date:					
Specified by user:					
Version: HYSYS v1.5.2 (Build 1706) Page No: 2 Of 2					

APPENDIX 3-2 FIG.3 Pg.3



HYSYS Workbook <b>PLANT-12 Dehy &amp; Reflux</b> Co mn 2070 FWHP.hsc						
Main: Streams						
Streams						
Name	1001	1002	1003	2001	2002	
Vapor Fraction	0.0000	1.0000	1.0000	0.9581	0.9409	
Temperature (F)	712.9	300.0	300.0	244.0	60.00	
Pressure (psia)	5745	5745	5745	3070	2050	
Molar Flow (lbmol/hr)	71.88	1084	1155	1155	1155	
Mass Flow (lb/hr)	1.491e+05	4.310e+05	4.451e+05	4.651e+05	4.491e+05	
Liquid Volume Flow (bbl/hr)	9938	4.078e+02	4.078e+02	4.472e+02	4.472e+02	
Heat Flow (Btu/hr)	-2.453e+05	-4.527e+04	-4.770e+04	-4.770e+04	-4.919e+04	
Comp Mole Frac Ethanol	0.0000	0.0001	0.0000	0.0039	0.0038	
Comp Mole Frac ICOD	0.0000	0.7131	0.8083	0.9581	0.9409	
Comp Mole Frac H2O	0.0000	0.0003	0.0039	0.0050	0.0050	
Comp Mole Frac Methanol	0.0000	0.2878	0.2313	0.2519	0.2519	
Comp Mole Frac Ethanol	0.0000	0.0001	0.0049	0.0048	0.0048	
Comp Mole Frac Propanol	0.0000	0.0014	0.0018	0.0018	0.0018	
Comp Mole Frac H2O	1.0000	0.0007	0.0022	0.0022	0.0022	
Name	3000	4001	4008	4100	4101	
Vapor Fraction	—	1.0000	0.9724	1.0000	1.0000	
Temperature (F)	—	80.00	8.778	—	—	
Pressure (psia)	—	2050	850.0	850.0	850.0	
Molar Flow (lbmol/hr)	—	1087	850.0	850.0	814.7	
Mass Flow (lb/hr)	—	4.310e+05	3.604e+05	2.112e+05	2.112e+05	
Liquid Volume Flow (bbl/hr)	—	4.278e+05	3.835e+05	2.472e+05	2.472e+05	
Heat Flow (Btu/hr)	—	-4.527e+04	-3.874e+04	-3.112e+04	-3.112e+04	
Comp Mole Frac Ethanol	—	0.0041	0.0043	0.0072	0.0072	
Comp Mole Frac ICOD	—	0.7092	0.7123	0.5352	0.5352	
Comp Mole Frac H2O	—	0.0003	0.0003	0.0038	0.0038	
Comp Mole Frac Methanol	—	0.2872	0.2843	0.4473	0.4473	
Comp Mole Frac Ethanol	—	0.0041	0.0037	0.0033	0.0033	
Comp Mole Frac Propanol	—	0.0018	0.0018	0.0018	0.0018	
Comp Mole Frac H2O	—	0.0043	0.0000	0.0000	0.0000	
Name	4110	4210	4215	5001	5002	
Vapor Fraction	1.0000	0.0000	0.0000	0.0000	1.0000	
Temperature (F)	725.7	60.01	116.4	80.00	82.33	
Pressure (psia)	3000	850.0	3800	3050	2000	
Molar Flow (lbmol/hr)	814.7	887.2	487.2	0.0000	1882	
Mass Flow (lb/hr)	2.312e+05	2.221e+05	2.221e+05	0.0000	4.333e+04	
Liquid Volume Flow (bbl/hr)	2.472e+05	1.877e+05	1.877e+05	0.0000	4.333e+05	
Heat Flow (Btu/hr)	-3.881e+04	-2.551e+04	-2.184e+04	0.0000	-4.812e+04	
Comp Mole Frac Ethanol	0.0072	0.0000	0.0000	0.0041	0.0041	
Comp Mole Frac ICOD	0.5352	0.9453	0.8153	0.7092	0.7123	
Comp Mole Frac H2O	0.0038	0.0076	0.0079	0.0053	0.0053	
Comp Mole Frac Methanol	0.4473	0.0328	0.0028	0.2872	0.2872	
Comp Mole Frac Ethanol	0.0033	0.0049	0.0049	0.0031	0.0031	
Comp Mole Frac Propanol	0.0018	0.0024	0.0024	0.0018	0.0018	
Comp Mole Frac H2O	0.0000	0.0000	0.0000	0.0043	0.0000	
APPENDIX FOR F143 P12						
Remarks:						
Date:						
* Specified by user.						
Version: HYSYS v11.2 (Build 1706)			Page No.		1	Of 2

# INTERNATIONAL SEARCH REPORT

International Application No  
PCT/US 00/33705

**A. CLASSIFICATION OF SUBJECT MATTER**  
IPC 7 C10L3/08 F02C3/22

According to International Patent Classification (IPC) or to both national classification and IPC

**B. FIELDS SEARCHED**

Minimum documentation searched (classification system followed by classification symbols)  
IPC 7 C10L F02C

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, PAJ, WPI Data

**C. DOCUMENTS CONSIDERED TO BE RELEVANT**

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 93 13307 A (HARVEY ROBERT D) 8 July 1993 (1993-07-08)	
A	US 4 733 528 A (PINTO ALWYN) 29 March 1988 (1988-03-29)	

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

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Date of the actual completion of the international search

27 March 2001

Date of mailing of the international search report

03/04/2001

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# INTERNATIONAL SEARCH REPORT

Information on patent family members

Intern. Application No.

PCT/US 00/33705

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